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The impact of time-varying CO_2 injection rate on large scale storage in the UK Bunter Sandstone

Clea Kolster[a,b,c,*], Simeon Agada[d], Niall Mac Dowell[b,c], Samuel Krevor[d]

[a] Grantham Institute for Climate Change and the Environment, Imperial College London, SW7 2AZ, UK
[b] Centre for Environmental Policy, Imperial College London, SW7 1NA, UK
[c] Centre for Process Systems Engineering, Imperial College London, SW7 2AZ, UK
[d] Department of Earth Science and Engineering, Imperial College London, SW7 2AZ, UK

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ABSTRACT

Carbon capture and storage (CCS) is expected to play a key role in meeting targets set by the Paris Agreement and for meeting legally binding greenhouse gas emissions targets set within the UK (Energy and Climate Change Committee, 2016). Energy systems models have been essential in identifying the importance of CCS but they neglect to impose constraints on the availability and use of geologic CO_2 storage reservoirs. In this work we analyse reservoir performance sensitivities to varying CO_2 storage demand for three sets of injection scenarios designed to encompass the UK's future low carbon energy market. We use the ECLIPSE reservoir simulator and a model of part of the Southern North Sea Bunter Sandstone saline aquifer. From a first set of injection scenarios we find that varying amplitude and frequency of injection on a multi-year basis has little effect on reservoir pressure response and plume migration. Injectivity varies with site location due to variations in depth and regional permeability. In a second set of injection scenarios, we show that with envisioned UK storage demand levels for a large coal fired power plant, it makes no difference to reservoir response whether all injection sites are deployed upfront or gradually as demand increases. Meanwhile, there may be an advantage to deploying infrastructure in deep sites first in order to meet higher demand later. However, deep-site deployment will incur higher upfront cost than shallow-site deployment. In a third set of injection scenarios, we show that starting injection at a high rate with ramping down, a low rate with ramping up or at a constant rate makes little difference to the overall injectivity of the reservoir. Therefore, such variability is not essential to represent CO_2 storage in energy systems models resolving plume and pressure evolution over decadal timescales.

1. Introduction

Carbon capture and storage (CCS) is expected to play a pivotal role in reducing greenhouse gas emissions and avoiding dangerous climate change (Energy and Climate Change Committee, 2016; IPCC, 2014; Kriegler et al., 2014; Budinis et al., 2016). Under the 2008 Climate Change Act, the UK has committed to reducing its greenhouse gas emissions by 80% from 1990 levels by 2050 and according to the Committee on Climate Change, CCS is critical in reaching this target at least cost (Comptroller and Auditor General, 2017; Committee on Climate Change, 2015). Evaluations for costs and deployment of low carbon energy systems are typically based on integrated assessment models that include the techno-economics associated with CCS development and risk. However, these typically assume a pressure vessel type description of CO_2 storage sinks, and do not include limitations that may be imposed by the storage reservoir as a result of sudden deployment or varying CO_2 injection rates (Ghambir et al., 2017). In this work, we use reservoir simulation to evaluate some of the potential issues that may arise from regional large scale deployment of CCS in the UK.

The Bunter Sandstone Saline aquifer has been identified as having a significant CO_2 storage potential (Williams et al., 2014; Noy et al., 2012; Thibeau et al., 2014; Heinemann et al., 2012; Smith et al., 2011). As a result, it has been subject to a number of numerical modelling studies evaluating the integrity of the reservoir seal and maximum safe overpressure (Heinemann et al., 2012), the effect of the reservoir's geological structure and heterogeneity on CO_2 storage efficiency (Williams et al., 2013) and the effect of large scale injection of CO_2 into the reservoir on brine displacement (Noy et al., 2012). A recent study conducted by Pale Blue Dot Energy for the Energy Technologies Institute found that injection into the Bunter saline aquifer will be key in providing the appropriate geographic spread and capacity to meet UK

* Corresponding author at: Grantham Institute for Climate Change and the Environment, Imperial College London, SW7 2AZ, UK.
E-mail address: clea.kolster10@imperial.ac.uk (C. Kolster).

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storage demand (ETI, 2016). The Bunter Sandstone has the advantage of being in close proximity to the Eastern coast where the UK has a large concentration of industrial and power plants (Comptroller and Auditor General, 2017; ETI, 2016), including the largest coal firing power station in the UK: Drax Power Station.

Importantly, it is likely that CO_2 storage reservoirs will be subject to dynamics across multiple time-scales. On a decadal time-scale, CCS capacity will be gradually deployed and ostensibly lead to an increase in target CO_2 injection rates. Meanwhile, the deployment of extensive amounts of intermittent renewable power could lead to displacement of thermal generation as well as an increased, hourly dependent, variability in storage demand for CO_2 from power (Mechleri et al., 2017a,b; Mac Dowell and Staffell, 2016; Mac Dowell and Shah, 2015). Investigating the effect these variable rates of CO_2 injection can have on regional reservoir behaviour and storage supply is the focus of our current study.

Studies have simulated varying rates of CO_2 injection over an extended period of time in order to understand the effects of large-scale CCS deployment. These have shown a clear link between reservoir injectivity and dynamic storage capacity, while showing no link between varying injection rate and overall plume migration or regional pressure build up (Xie et al., 2016; Deng et al., 2012; Bannach et al., 2015; Farhat and Benson, 2013; International Energy Agency Grennhouse Gas R and D Programme, 2010; Wiese et al., 2010). In a study conducted by Wiese et al. (2010) numerical simulations are used to look at the impact of temporal variations in CO_2 injection through a single well into a saline aquifer in order to mimic the impact of CO_2 capture variability. They find that in the long term such variability has little impact on storage capacity. Bannach et al. (2015) conduct a dynamic simulation of large-scale industrial rates of CO_2 injection with seasonal variation into the Volpriehausen sandstone in North Germany. They find that varying CO_2 injection rates have the largest negative effect on overall injectivity within the first years of operation when compared to injection at a constant rate. In both cases, the study finds that the pressure build up is highest in the first few years of injection and decreases with time. The study also shows that reducing permeability by 50% generates a proportional decrease in the injection rate. Xie et al. (2016) investigates injectivity of saline aquifer sites in the Ordos Basin of China and compares the storage capacity of sites within the Ordos Basin using analytical methods and numerical simulations. The study highlights that, when conducting numerical simulations, a lower injectivity is obtained, compared to injectivity obtained from an analytical solution for injection. This is because the numerical simulation incorporates the effects of reservoir heterogeneity and the evolution of relative permeability. Deng et al. (2012) looks at the effect of industrial-scale CO_2 injection on injectivity over time of a model of the Weber Formation in Wyoming. This study finds that injectivity is limited by the safe injection pressure imposed and the heterogeneity of the reservoir model over 50 years of injection. Storage capacity of a reservoir over time will also depend on such reservoir conditions including boundary conditions, density and viscosity of the fluids, permeability and porosity distributions, reservoir thickness and depth (Birkholzer and Zhou, 2009; Bachu, 2015).

This study focuses on these issues in the UK context of large-scale regional CCS deployment. The objective is to improve understanding of potential limitations to CO_2 storage by considering a variety of scenarios for CCS development. These scenarios are grouped into three categories designed to encompass the range of future potential CO_2 storage demand scenarios.

Firstly, the UK is showing an increasing variability in its energy portfolio with increasing penetration of intermittent renewable energy sources and nuclear power. Hence, CCS with power and industry may become more or less important at different points in time, resulting in varying CO_2 storage demand. In addition, meeting storage demand may be conditional to reservoir properties around a selected and developed injection site. In an initial set of injection scenarios, we investigate the sensitivity of storage supply to varying and cyclical fluctuation in rates of demand and injection site selection, which will differ in local permeability and depth.

Secondly, between 2007 and 2015 the UK conducted two CCS competition projects intended to serve as a jumpstarter for the technology. The last one was cancelled in November 2015 due to a lack of allocated budget (Comptroller and Auditor General, 2017). The White Rose CCS project, led by a consortium company called Capture Power Limited, aimed to capture CO_2 by retrofitting a Drax Power Station coal firing unit with CCS and inject the CO_2 into the Bunter Sandstone (Global CCS Institute, 2016). This demonstration project aimed at capturing 2 $MtCO_2$/year (Dixon and Mitchell, 2016; Furnival et al., 2014). We envision a future for CCS in the UK starting with a similar demonstration size project and eventual expansion to retrofit capture onto more power plant units. Each CCS plant may start development at different points in time and take several years to construct (Mendelevitch, 2013) adding to the imposed variability onto the storage system. In a second set of CO_2 injection scenarios, we investigate the impact of gradual industrial-scale CCS deployment on CO_2 storage supply.

Thirdly, energy systems models suggest deployment rates for CCS to meet emissions reduction targets while meeting electricity demand (Mac Dowell and Staffell, 2016). However, sufficient injectivity and reservoir pressurization will be key in this match between the capture system and storage needs (Birkholzer and Zhou, 2009; Mijic et al., 2014; Hortle et al., 2014). The feedback between the energy system and the CO_2 storage demand is investigated here with a third set of injection scenarios based on previous energy systems modelling work (Mac Dowell and Staffell, 2016).

2. Methodology

2.1. Geological reservoir model

The Bunter Sandstone is located offshore the East of England in the UK Southern North Sea and is part of a larger reservoir rock unit of which the onshore part is known as the Sherwood Sandstone Group. The geological and dynamic simulation model used in this work to represent the Bunter Sandstone regional aquifer was developed from the British Geological Survey (BGS) model presented by Noy et al. (2012). The model area chosen is bounded by an overlying seal of mudstones and evaporites that constitute the Upper Triassic Haisborough Group and the Bunter Shale Formation as an underlying seal, each with permeabilities of the order of microDarcies. The outer boundary of the model is also assumed to be impermeable as it consists of a series of discontinuous salt walls and erosional margins that result from major fault zones (Noy et al., 2012). The presence of gas fields within the model area, including the Esmond, Forbes and Gordon fields as well as the Hewett Field Group just outside of the model boundary, suggest an effective reservoir seal (Heinemann et al., 2012). However, uncertainty remains around the potential presence of an outcrop to the seabed (Williams et al., 2013; Noy et al., 2012; Thibeau et al., 2014). An outcrop to the seabed could provide pressure relief as a result of expulsion of brine from the reservoir while posing a risk for CO_2 leakage into the seabed. However, the simulations scenarios run as part of this study showed that neither of these occur over the time periods considered i.e. 100 years.

The model covers an area of approximately 143 km East to West and 125 km North to South, and uses a grid of 250 (x) × 285 (y) × 25 (z) elements sized 500 m by 500 m. The reservoir is divided vertically into 25 layers, of which layers 1–6 of the coarse grid model represent the impermeable caprock region. Well penetration data were used to obtain depth at different locations in the reservoir. The mean depth of the reservoir model is 1850 m. A mean reservoir temperature of 65 °C was assumed, while an average reservoir pressure of 19.5 MPa, an average porosity of 20% and permeability of 100 mD was used. Brine salinity

was set to 130,000 ppm and rock compressibility to 4.5×10^{-10} Pa^{-1}. These values were the same as those used in Noy et al. (2012). Dissolution of CO_2 in the formation pore-water was also included in the model as done by Noy et al. (2012).

Using the reservoir simulator ECLIPSE 100, the model is set up as a CO_2-brine black oil model with pressure, volume and temperature (PVT) data computed using the method described by Hassanzadeh et al. (2008). Relative permeability data tables for water and gas were based on core-flood experiments on a water-wet Bunter sandstone sample (Reynolds, 2016). Recognizing the importance of capillary trapping in safe CO_2 sequestration (Bachu, 2015; Spiteri et al., 2005; Raza et al., 2015), a Killough hysteresis model (Killough, 1976) was implemented to account for hysteresis in the gas relative permeability (Juanes et al., 2006).

2.2. Simulation parameters and constraints

The reservoir model includes 12 injection sites with a minimum distance from site to site of 30 km and a large site diameter (0.3048 m or 1 foot). We assume that, in practice, each injection site could represent several wells. The number of wells deployed at a given injection site will typically depend on the trade off between the cost of adding a well and the amount of CO_2 that can be safely injected into one well without overpressure (Carneiro et al., 2015). In practice, this may also depend on the permeability of the targeted field. The Sleipner project for example only needed one injection well, while the In Salah project, with the same targeted injection rate (1 $MtCO_2$/year) but lower permeability, required 3 injection wells (Hosa et al., 2011; Vernon et al., 2013). The locations of the 12 injection sites were based on proximity to existing infrastructure in place from gas fields in the area. The injection sites are completed in every layer of the reservoir (layers 6–25). The fluid injection into the sites modelled is limited by a bottom hole pressure (BHP) constraint. This is set at 75% of the estimated lithostatic pressure at each injection site, which also represents the lower bound of reported leak-off tests at depths greater than 1000 m (Noy et al., 2012). Leak-off tests are carried out in order to give a good indication of the fracture pressure of a formation. The lithostatic pressure gradient assumed is 22.5 kPa/m, which implies that the deeper the site, the higher its bottom-hole pressure limit will be Noy et al. (2012). Other studies use more or less stringent pressure build up limits ranging from 60% to 90% of lithostatic pressure (Noy et al., 2012; Heinemann et al., 2012; Bachu, 2015). Reduced uncertainty with regards to pressure gradients in the reservoir may lead to less stringent limits on the bottom hole pressure and quicker injection.

In simulation studies aimed at representing CO_2 injection on a regional scale and due to the coarseness of such a model (i.e. having grid blocks of the order of 10 s or 100 s of metres), modelling injection of CO_2 with one large injection site is customary and captures the key reservoir behaviour (Birkholzer and Zhou, 2009; Leetaru et al., 2009). In this study the grid resolution is of 500 m × 500 m, which is similar to other studies looking at injection over large regions (Hortle et al., 2014). Simulations that focus on a single injection site with several wells will use a more refined grid resolution of the order of 10 s m^2 (Furuvik and Halvorsen, 2015). Here, the grid cells that include an injection site and the three grid cells in each *x*-direction and *y*-direction of the grid cell with the injection site are refined. These are refined by a factor of 11, bringing the grid resolution to 45.5 m × 45.5 m in the grid cells surrounding and including each injection site.

In this study, we consider a timeline of CO_2 injection and monitoring that commences in year 2030, which would be operated for under 100 years. Within this timeline we impose closed lateral and vertical boundaries providing a conservative estimate of reservoir pressurization given that greater pressure increase will occur. The results of CO_2 injection obtained from ECLIPSE 100 simulations are evaluated and analysed in Petrel. In this study we consider a base case scenario of 24 $MtCO_2$ injection per year in the field, which is split evenly between the 12 injection sites. While studies by Noy et al. (2012) and Farhat and Benson (2013) consider higher rates of injection per site at 5 $MtCO_2$/year, on average, industry practice in the North Sea would suggest an injection rate per site to be 1–2 $MtCO_2$/year (Chadwick, 2013; Mathias et al., 2013; Hosa et al., 2011). The model parameters are summarized in Table S1 in Supplemental Materials S5.1.

Table 1
Depth and bottom hole pressure (BHP) limit of 12 base case injection sites obtained from the BGS Bunter Sandstone reservoir model.

Injection site	Depth (m)	BHP limit (MPa)
1	1751	29.54
2	2007	33.87
3	1742	29.39
4	1743	29.42
5	2564	43.26
6	2020	34.09
7	1971	33.26
8	2311	39.00
9	1517	25.60
10	1729	29.18
11	1738	29.33
12	1795	30.30

2.3. Injection rate scenarios and injection site selection

Three sets of reservoir simulations were conducted based on three sets of injection scenarios summarized in Table 2. The first set of injection scenarios covers highly fluctuating cyclic variation of CO_2 storage demand rate regimes. This includes a sensitivity analysis that highlights key injection rate differences that may stem from variation in permeability and depth at different injection site locations. The second

Table 2
Three sets of injection scenarios based on storage demand for the field: (1) four high amplitude cyclic fluctuations of target injection rates (rates given as: starting rate/2nd cycle rate) compared with a Base Case Scenario of target field total 24 $MtCO_2$/year injection, (2) storage demand for five CCS deployment scenarios based on hypothetical CO_2 capture rates obtained from Drax power plant and number of units, demonstration (DEM) or large-scale (LS) deployed, (3) three UK CCS with coal deployment and displacement scenarios determining storage demand rates for the Bunter Sandstone.

Set	Scenario	Target injection rate(s) ($MtCO_2$/year)	Variation	Inj. time (years)	Unit deployment
1	Base case	24	Constant	50	6 × LS
	± 80%	43.2/4.8	Every 5 years	50	6 × LS
	∓80%	4.8/43.2	Every 5 years	50	6 × LS
	± 80%	43.2/4.8	Every 2.5 years	50	6 × LS
	v80%	4.8/43.2	Every 2.5 years	50	6 × LS
	Sensitivity	1.0	Constant – one site at a time	50	Injection sites 1, 5, 9

		Target peak inj. ($MtCO_2$/year)	Peak inj. year	Inj. time (years)	Unit deployment
2	Drax 1	14	2045	85	1 × DEM, 3 × LS
	Drax 2	14	2040	75	1 × DEM, 3 × LS
	Drax 3	14	2045	55	1 × DEM, 3 × LS
	Drax 4	14	2060	70	1 × DEM, 3 × LS
	Drax 5	22	2050	60	1 × DEM, 5 × LS

		Target peak inj. ($MtCO_2$/year)	Peak inj. year	Inj. time (years)	Variation level
3	E-system 1	12	2030	50	High-low-end
	E-system 2	12	2050	50	Low-high-low-end
	E-system 3	11	2030	50	Constant

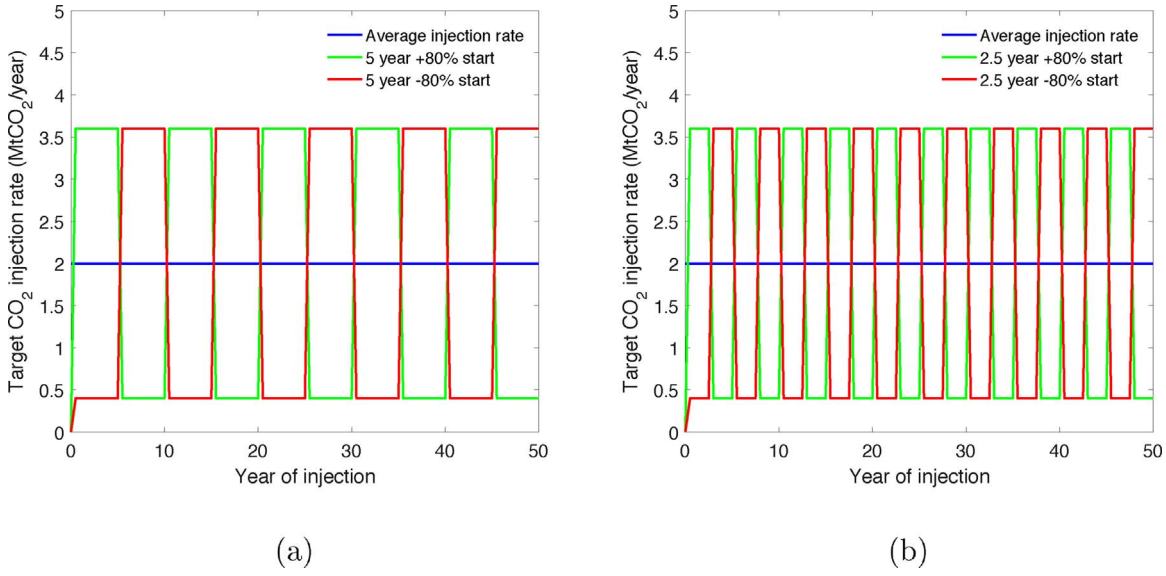

Fig. 1. Target injection rates varying every 5 years (a) and every 2.5 years (b) at 80% above and below an average target injection rate of 2 $MtCO_2$/year starting at the higher or lower amplitude of injection.

set of injection scenarios describes injection demand from gradually increasing potential UK CCS deployment rates. These first assume that a demonstration plant of the same size as White Rose CCS is deployed and then CCS is retrofitted onto some of the remaining Drax Power Plant units. The third set of injection scenarios is based on the output and extension of an energy systems model for CCS deployment on coal fired power plants in the UK.

2.3.1. Sensitivity of plume migration and pressure to varying injection rates, depth and permeability – set 1

In a first set of reservoir simulation scenarios of dynamic CO_2 injection, we investigate the impact of cyclic variations in CO_2 injection. This allows us to understand from a theoretical standpoint why variation in CO_2 injection may have an effect on reservoir behaviour and storage efficiency. Hence, in these scenarios, represented in Fig. 1, we varied the amplitude of target injection per site (by 80% above and below the average) and the cycle period (2.5 years and 5 years). These were compared to a constant rate of CO_2 supply over the same total duration of operation, 50 years. The average rate of CO_2 supply and target injection was set at 24 $MtCO_2$/year for the whole reservoir and split evenly between the 12 injection sites.

We highlight the effect of permeability and depth on injectivity of the reservoir by considering the injection of 1 $MtCO_2$/year for 50 years in three distinct sites, 1, 5 and 8. The near-well bore horizontal permeability, depth and lithostatic pressure at each site is summarized in Table 3. Compared to the average reservoir permeability and depth, injection site 1 and 8 are in low permeability shallow and deep zones respectively, while injection site 5 is in a high permeability, deep zone. The lithostatic pressure at a given site is proportional to the depth at the injection site. The horizontal permeability distribution is shown in Fig. 2. Here, while injecting into one site at a time, all other sites are closed.

Table 3
Horizontal permeability, depth, and lithostatic pressure near injection sites 1, 5 and 8 compared with average reservoir characteristics.

Site	Permeability (mD)	Depth (m)	Lithostatic pressure (MPa)
Injection site 1	21	1751 (shallow)	39.39
Injection site 5	283	2564 (deep)	57.68
Injection site 8	36	2311 (deep)	52.00

2.3.2. Injection scenarios envisioned for UK government led regional CCS deployment – set 2

Based on the UK government's past CCS deployment strategy we consider five scenarios for CO_2 storage demand from the Bunter Sandstone, summarised in Table 2. The first four scenarios of CO_2 storage demand assume that CCS deployment peaks at 14 $MtCO_2$/year in 2045, 2040, 2045 and 2060, which is equivalent to one demonstration plant and three Drax Power Plant units retrofitted with CCS. In a fifth scenario, we consider that CO_2 storage demand peaks at 22 $MtCO_2$/year in 2050. Each scenario is initiated in 2030 with target injection rates equivalent to the capture rate of 2 $MtCO_2$/year, that we refer to as the demonstration plant (DEM) and subsequent plants correspond to a rate of capture at 4 $MtCO_2$/year, that we refer to as the large-scale plant (LS).

In considering these scenarios we investigate trade offs between an expansive deployment strategy, where all 12 sites are in place for the start of injection (injection is split evenly across all sites), and limited site deployment strategies that split injection in the field into a maximum of 6 selected sites. We draw from the oil and gas industry in North America to describe storage developers, who are likely to build injection sites progressively in response to short term demand (IHS Global Inc., 2013). This minimizes upfront capital cost. Hence, we assume four improved injection strategies with a reduced number of total sites targeted. These are summarized in Table 4. In a first site deployment strategy we consider splitting target injection into sites 1–6 throughout the full injection period (‘6 sites’). In a second strategy we consider targeting injection into sites on a need-only basis with a maximum of 6 injection sites in use at any given time (‘Need base deployment’). Third, we consider targeting injection into 2 first sites then splitting the CO_2 supply into four more sites pre-empting that storage demand will increase in a few years (‘Progressive deployment’). Finally, we consider strategically choosing the deepest sites in which to target injection (‘Deep sites’), which will have the highest limits on bottom hole pressure. The ‘Deep sites’ injection strategy assumes that the deepest sites, 5 and 8 (see Table 1) are first deployed to meet capture rates from the demonstration plant (2 $MtCO_2$/year), then, before the 1st large scale CO_2 capture plant is deployed, injection is split into the next four deepest sites, 2, 6, 7 and 12. The choice of site as a function of depth is based on the information provided in Table 1.

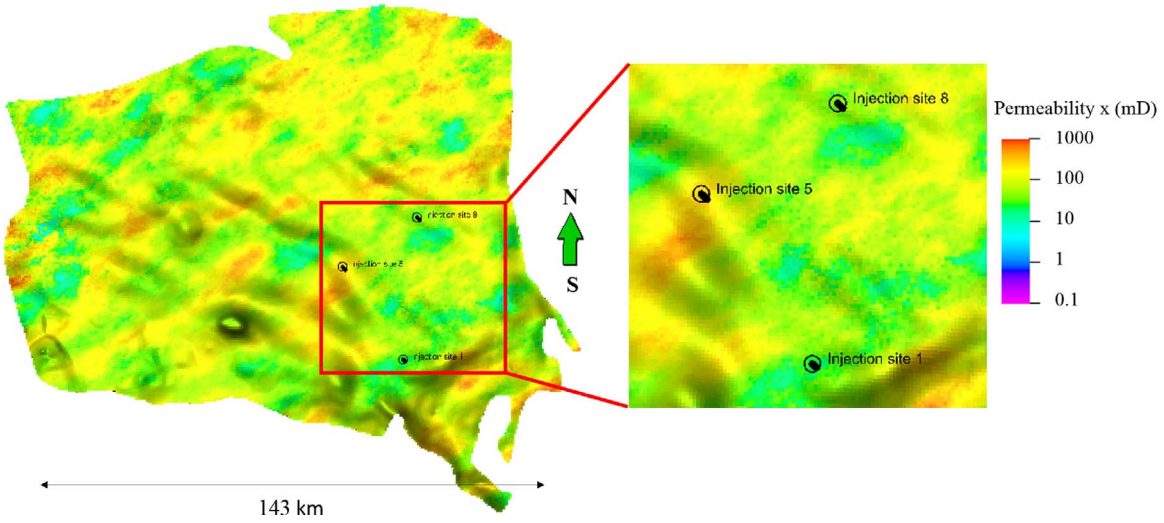

Fig. 2. Horizontal permeability surrounding injection sites 1 and 5 in the heterogeneous Bunter Sandstone reservoir field model.

2.3.3. Impact of varying storage demand based on a systems model output of UK coal power with CCS – set 3

In a third set of injection scenarios (see Fig. 3), we take the deployment rates for CCS based on previous energy systems modelling work (Mac Dowell and Staffell, 2016). This earlier work uses a UK based electricity market model that integrates UK emissions reduction plans with a portfolio of clean energy options in order to establish the role that coal with CCS may play in the future energy mix. It shows 'coal CCS' starting with a high capacity factor and thus a high CO_2 storage demand in 2030, which slowly decreases over the 50-year timeline as a result of increasing market penetration of renewable energy (E-system 1). We simulate this target injection into the reservoir model and compare the injectivity with two injection scenarios of identical average target injection rate over the 50 years considered. The first comparative scenario (E-system 2) assumes a ramp up of 30 years before reaching a peak of 12 $MtCO_2$/year storage demand in 2060 followed by a sharp decline in demand. Meanwhile the second comparative scenario (E-system 3) assumes a constant CO_2 storage demand rate.

3. Results and discussion

3.1. Sensitivity of plume migration and pressure to varying injection rates, depth and permeability – set 1

Fig. 4 shows the CO_2 plume distribution and pressure development in the reservoir as a result of constant injection over 50 years and varying CO_2 injection by 80% every 2.5 years starting at the highest rate. The gas saturation and pressure development distribution maps for the other scenarios in set 1 are shown in S5.2. The static image of reservoir behaviour after 50 years of CO_2 injection are presented in these figures at the 15th layer of the reservoir model. The plume migration differs because of variable injectivity across sites (Fig. 4a and b). This is because the geology around certain sites is more favourable to higher initial injection rates than others. We observe that after 50 years of injection, all scenarios have a similar plume extent.

Similarly, the pressure distribution in the reservoir after 50 years of injection for all 5 injection rate scenarios are alike (Fig. 4c and d). Pressure in the reservoir is higher around the same South-Eastern area reaching pressure up to 350 bar, while remaining lowest in the North-West boundary of the model, between 100 and 150 bar. Average pressure build up in the reservoir is highest for the case of constant site injection, at 23% above original pressure, because cumulative CO_2 injection is highest. Meanwhile, the lowest pressure build up is 20% higher than original pressure, found at 50 years of the 5-year cycle injection starting at the higher bound rate (± 80%). In all varying rate scenarios, the average reservoir pressure, limited by injectivity in the early years of injection, remains 1–3% lower than that of constant injection throughout the total injection period. This is because lower total volumes of CO_2 were injected throughout the simulation period as a result of lower injectivity at the start of injection. This, however, is an artefact of artificially low injectivity at the beginning of the simulations (Mathias and Gluyas, 2013) and will not be a feature of real injection projects.

The analysis shows that the simulated reservoir dynamics associated

Table 4
Injection site deployment strategies to meet the storage demand scenarios for the UK government CCS deployment strategy (Set 2, Table 2).

Strategy name	Characteristic deployment/shut down	Description
12 sites	Expansive/immediate	Reservoir target injection rate from storage demand is split evenly in all 12 sites at the start of CCS deployment and for the whole simulation period.
6 sites	Limited/immediate	Reservoir target injection rate from storage demand is split evenly in sites 1–6 at the start of the CCS deployment period.
Need base deployment	Limited/gradual	Injection in demonstration years (2 $MtCO_2$/year) is targeted and split evenly at injection sites 1 and 2, and then targets sites 1–6 when large-scale capture units add to CO_2 storage demand. Sites are then closed down one by one as target demand for storage decreases step-wise.
Progressive deployment	Limited/gradual	Starting with injection targeted to sites 1 and 2, half way through the demonstration period with 2 $MtCO_2$/year storage, injection is split evenly to sites 1–6. Sites are then closed down one by one as target demand for storage decreases step-wise.
Deep sites	Limited/gradual	Sites 5 and 8 are targeted first when demonstration plants are providing demand, then half way through the demonstration period, injection target is split evenly between the 6 deepest sites in the field 2, 6, 7 and 12. Site shut down is also conducted progressively in response to decreasing demand.

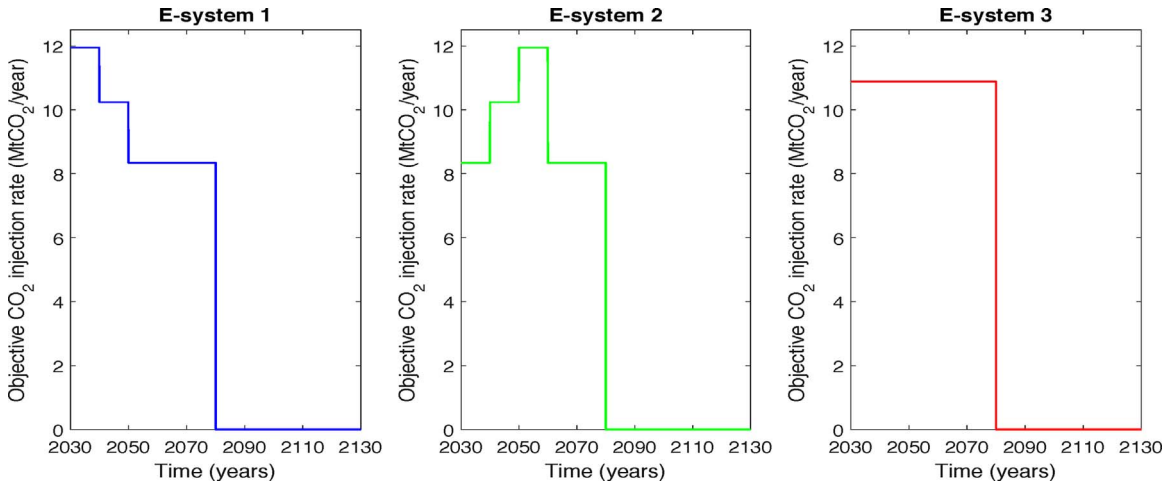

Fig. 3. Objective (target) injection rates for three CO_2 capture rate deployment scenarios (Mac Dowell and Staffell, 2016).

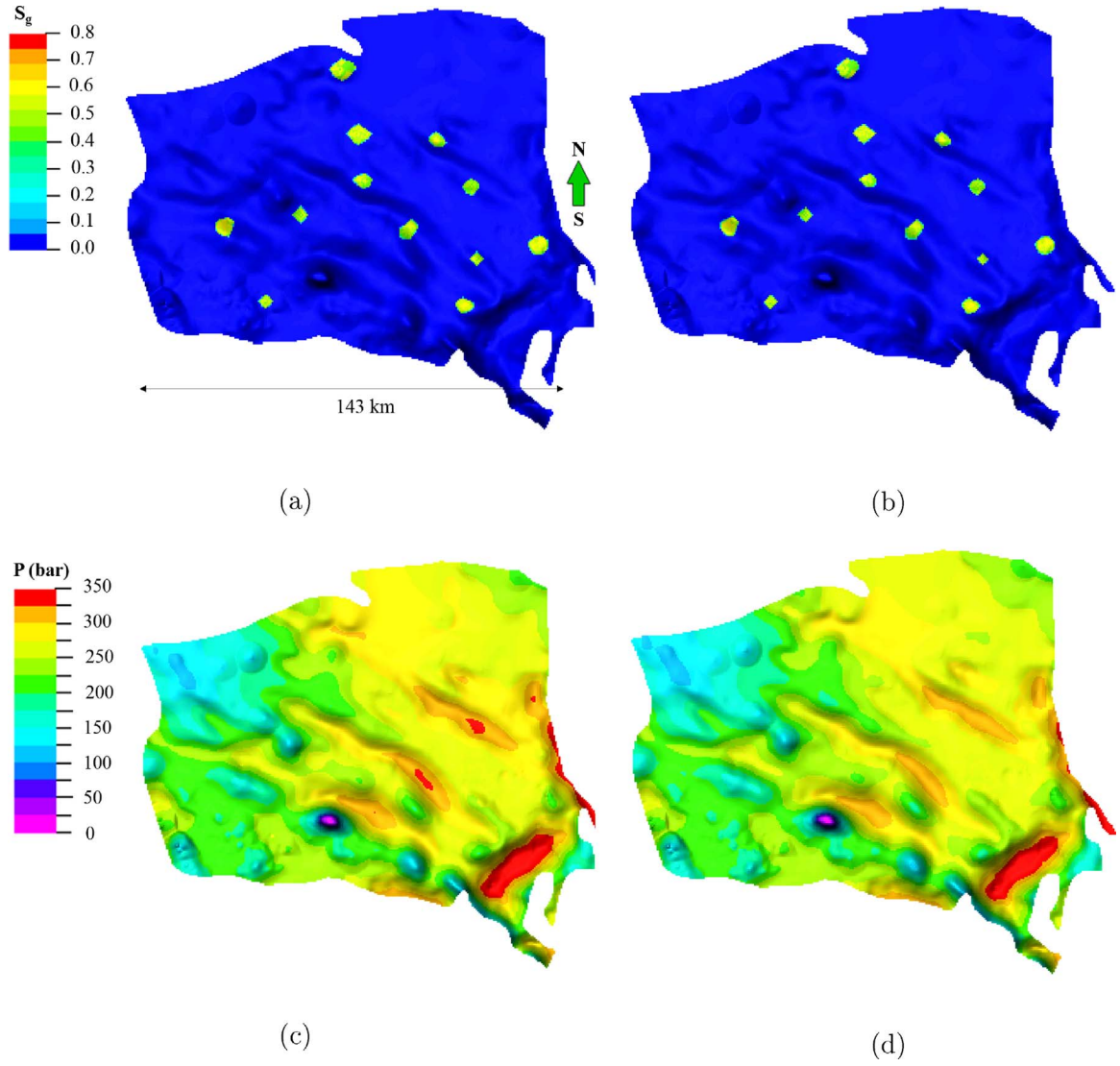

Fig. 4. Gas saturation S_g and reservoir pressure P after 50 years of constant CO_2 injection in all 12 sites at 2 $MtCO_2$/year (a), (c) and after 50 years of varying CO_2 injection rate by 80% above and below the average 2 $MtCO_2$/year every 2.5 years (b), (d).

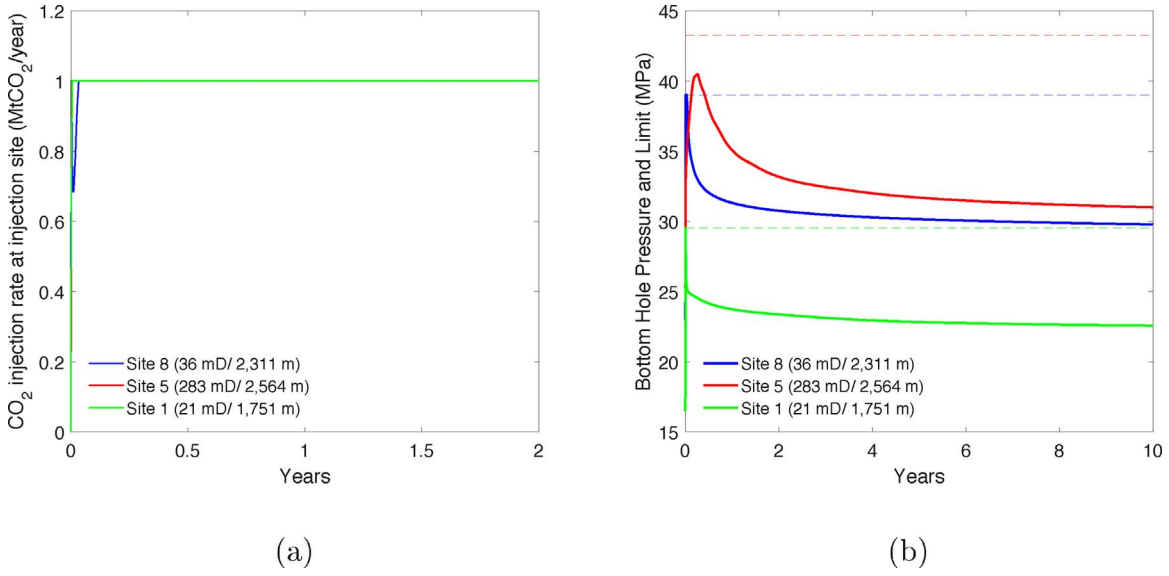
CO2 injection rate at injection site (MtCO2/year)
Years
Site 8 (36 mD/ 2,311 m)
Site 5 (283 mD/ 2,564 m)
Site 1 (21 mD/ 1,751 m)
(a)
Bottom Hole Pressure and Limit (MPa)
Years
Site 8 (36 mD/ 2,311 m)
Site 5 (283 mD/ 2,564 m)
Site 1 (21 mD/ 1,751 m)
(b)

Fig. 5. CO_2 injection rate in the first 2 years of injection (a) and bottom hole pressure in the first 10 years of injection (b) at the respective site in response to the targeted injection of 1 $MtCO_2$/year in each site. The dotted lines in (b) refer to the bottom hole pressure limit for each site.

with injecting at periodically varying rates of CO_2 is similar to injecting at constant rates of CO_2 over the periods considered. This shows that high amplitude rate fluctuations are not important to take into account when evaluating large volume injection over decade-long timescales. Hence, assuming a constant average rate of injection can prove to be sufficient in representing CO_2 storage in first-order systems models so long as the total volume of CO_2 injected over that time period is properly represented.

Fig. 5a shows the sensitivity of injectivity to near-site permeability and depth. Early time spikes in pressure, followed by subsequent decreases in pressure, are discounted as girding artefacts. Pickup et al. (2012) and Mathias and Gluyas (2013) found that similar early-time injection rate delays are a result of the grid scale used for the simulation model. The bottom hole pressure at each injection site is appropriately represented following the early-time evolution in Fig. 5b. The bottom hole pressures are bounded by the maximum allowable pressure limit at each injection site. After 10 years, the pressure evolution in the wells is free from gridding artefacts. All three sites exhibit pressure well below the limiting threshold. Site 5, at a depth of over 2500 m and near-site horizontal permeability over 280 mD, is farthest from the limit. This sensitivity analysis suggests that at higher rates of injection, near-well bore permeability and depth can become key drivers for injectivity due to the effect of the bottom hole pressure limit as shown in our earlier work (Agada et al., 2017). Deeper sites however will require higher drilling and completion costs for wells. We find that at such rates of injection, there will not be a problem reaching sufficient injectivity in time to meet storage demand.

3.2. Injection scenarios envisioned for UK government-led regional CCS deployment – set 2

Fig. 6 presents actual injection rates achieved for deployment scenarios Drax 1 and Drax 4 and for all five deployment strategies (summarized in Table 4). Scenarios Drax 2, 3 and 5 are described in more detail in Supplemental Materials S5.3.2. These results show that splitting injection into all 12 sites in the field and initiating injection at 2 $MtCO_2$/year results in target injection rates being met for the majority of the simulation period. This is the case whether the target peak injection rate is 14 $MtCO_2$/year or 22 $MtCO_2$/year, reflecting that limitations are imposed by injectivity constraints, not volumetric constraints.

We compare the expansive, ‘12 sites’ deployment strategy to injection strategies with different levels of limited site deployment. We find that in Scenarios Drax 1 and 4, the other injection strategies result in a small shortfall in injection rate, compared to the target injection rate, at their peaks of ramp up, in 2055 and 2070 respectively. This difference however is very small with a reduction in injectivity of 3.4–3.9% for Drax 1 and 3.9% for Drax 4 in all reduced injection strategies. In rapidly increasing storage demand scenario Drax 1, the ‘deep sites’ injection strategy shows slightly better injectivity than ‘6 sites’, ‘Need base’ and ‘Progressive’ deployment strategies, with a 3.4% reduction in injectivity compared to 3.9% for the latter three by year 2055. In slowly increasing deployment scenario Drax 4, the injection strategies do no have an effect on the ability to ramp up the CO_2 injection rate in response to an increasing storage demand and all have a 3.9% reduction in injectivity by 2070 compared to the ‘12 sites’ strategy. Such a small difference, however, is well within the uncertainty of the outcomes. These results suggest that there is no substantial benefit to deploying large infrastructure upfront to achieve initially low injection rates equivalent to one or two demonstration units (‘12 sites’ and ‘6 sites’ strategies), but rather adopt a deployment strategy that meets storage demand as it increases progressively (‘Need base deployment’, ‘Progressive deployment’ and ‘Deep sites’ strategies). Meanwhile, there may be a trade off in deploying higher cost injection sites earlier rather than later (i.e. deep sites requiring more costly drilling and completion work).

In all 5 Drax CCS deployment scenarios considered here, the total targeted CO_2 injection over the project lifetime is less than or equal to 1 $GtCO_2$. This is in agreement with studies assessing the dynamic storage capacity of the Bunter Sandstone Formation. Heinemann et al. (2012) assesses the dynamic storage capacity of the Bunter Sandstone to be between 3.8 and 7.8 $GtCO_2$ for 30 years of injection, while Noy et al. (2012) finds a more stringent estimate of 0.75–1 $GtCO_2$ for a 50-year injection period.

From a systems level perspective these results suggest that the reservoir behaviour at these levels of injection is indifferent to the rate at which target injection increases to meet increasing demand and the rate at which injection sites are deployed to meet it.

3.3. Impact of varying storage demand based on a systems model output of UK coal power with CCS – set 3

Energy systems models describing the UK's future energy mix still consider a proportion of coal consumption, which remains one of the

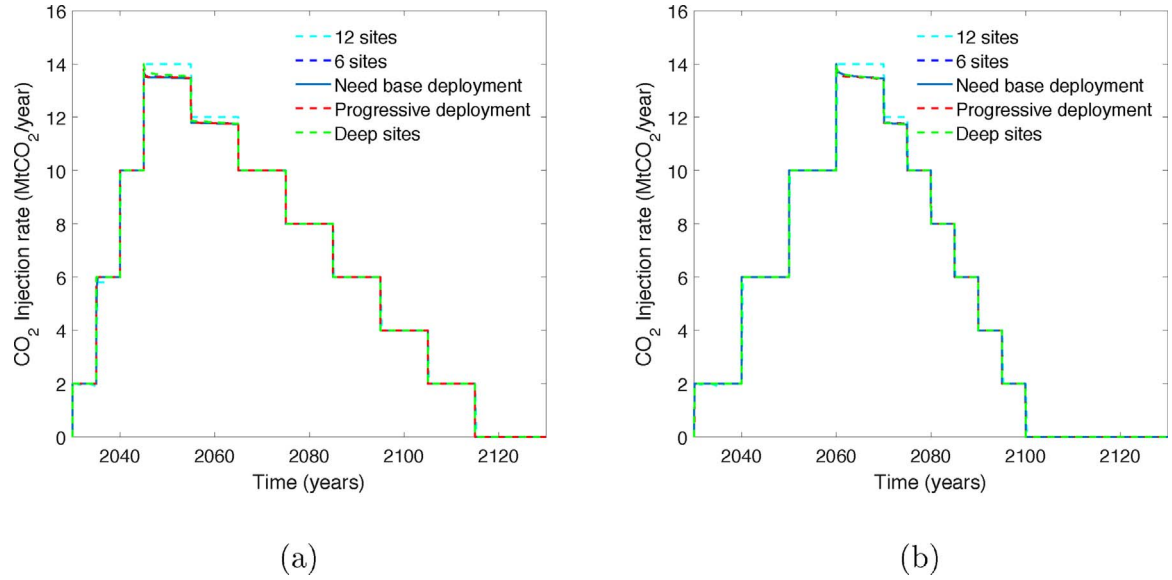

Fig. 6. Graph showing CO_2 injection rates obtained as a result of 5 injection site deployment options for storage demand scenario Drax 1 (a) and Drax 4 (b).

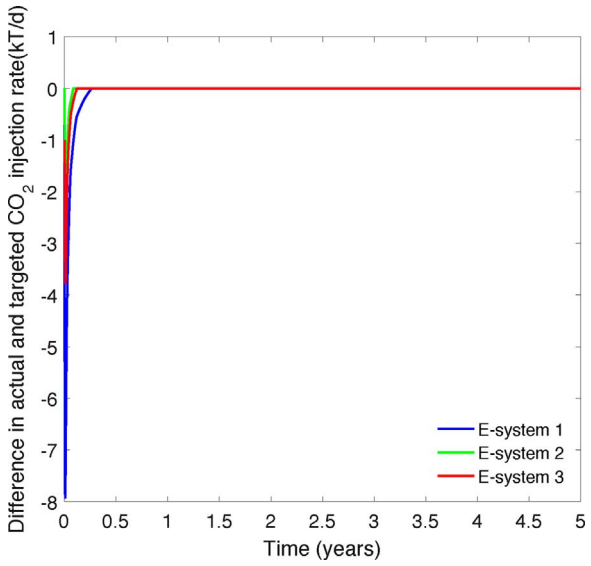

Fig. 7. Graph showing the difference between the CO_2 injection rate achieved and the target CO_2 injection rate for scenarios E-System 1–3 of Set 3 as described in Table 2.

main drivers for an imminent need for CCS. Fig. 7 shows the difference between the daily target injection rate and the actual injection rate for the 3 scenarios considered in set 3 (E-system 1–3) within the first five years of injection. We recall that injection is split evenly between all 12 sites described in the Bunter Sandstone reservoir model. We find that there is an insignificant difference in reaching the target injection rate in each of these scenarios. This is regardless of whether injection is initiated at a high rate with progressive ramp down associated with a reducing 'coal CCS' capacity factor (E-system 1), a lower initial target rate with progressive ramp up of injection associated with increasing the capacity factor for 'coal CCS' (E-system 2) or at a constant average rate of target injection over a 50-year project scope (E-system 3). The early time limits on injection are gridding artefacts that do not impact later time pressure evolution (Pickup et al., 2012; Mathias and Gluyas, 2013). Hence, these results suggest that varying the rate at which injection takes place in the reservoir does not have an effect on the ability to meet storage demand. Therefore, CCS deployment rate predictions that result from energy systems models should be able to consider, that, within the pressure limitation range of each injection site, injection rate variations including ramping up or down will not have an effect on storage capacity and reservoir injectivity.

4. Conclusions

In this study we evaluated potential limitations to subsurface storage capacity over yearly and decadal time scales that could result from time-varying storage demand. We considered three sets of scenarios: a theoretical scenario set to explore the effect of time varying rate amplitude, frequency and site location, a set based on the past UK government deployment strategy in the Southern North Sea, and a set based on deployment predictions from an energy systems model of the UK for coal power with CCS.

As a result of a first set of injection scenarios, we found that varying amplitude and frequency of CO_2 storage demand has little effect on reservoir pressure response and plume migration. Hence, as long as the total amount of CO_2 injected over several decades is represented in the storage system model, there is no need to include granular variation in injection rates for first order modelling of the type used in systems models. By investigating the pressure build up and injection rate at different injection sites in the reservoir model, we found that injectivity does not vary with time and injection rate per site will be dominated by near-well bore permeability and depth.

In a second set of injection scenarios, we envision UK government led CCS development for different storage infrastructure deployment strategies. We find that reduced injection site deployment, to meet increased storage demand, has no substantial effect on the ability to store CO_2 in the reservoir. In addition, we find that this is the case regardless of the rate at which injection is ramped up. Therefore, we suggest that injection sites can be deployed as needed and progressively instead of incurring a large upfront cost of deployment to meet future storage demand. Also, we highlight that there may be a trade-off when choosing the sites to deploy first as deeper sites for example will be more costly but may allow for higher injection rates later on.

In the final set of injection scenarios we look at the reservoir response to CO_2 storage demand based on energy systems models predicting the UK coal power with CCS deployment. We find that such energy systems models that include CCS do not need to take into account any effects related to the initial response to variation in CO_2 storage demand other than the usual effects related to reservoir permeability and injection.

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Appendix A. Supplementary data

Supplementary data associated with this article can be found, in the online version, at http://dx.doi.org/10.1016/j.ijggc.2017.10.011.

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